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COMPARISON OF ECONOMICS OF IN SITU
COAL GASIFICATION WITH SURFACE PROCESSING

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ABSTRACT

The Los Alamos Scientific Laboratory (LASL) concept for underground coal conversion (gasification) involves preliminary hot-gas drying and pyrolysis steps followed by gasification of the resulting char through combustion with a carbon dioxide-oxygen mixture. This staged recovery process produces both an enhanced-BTU (1300 BTU/scf) fuel gas to mix with natural gas and a clean, low-BTU gas for electricity production. Detailed engineering and economic analyses have been completed that point to the feasibility of this approach.

Comparable economic analyses, all based on costs of existing Lurgi surface technology, are given for three processes with roughly similar commercial goals, i.e., the LASL concept above; Lurgi gasification of surface-mined coal, followed by gas cleanup; and a steam-oxygen underground process analogous to those processes used at Hanna and Hoe Creek, WY, followed by gas cleanup. All proposed cleanup procedures for the gasification product employ existing technology and meet air quality standards.

The analyses indicate that the costs of Lurgi and of current underground coal conversion technologies are similar at the present stage of the development of in situ technology. Simple modifications of the methods of underground conversion which are evaluated in the paper, can be expected to improve the byproduct recovery and to much reduce the capital costs of conversion--such converstion systems appear to be economically competitive with strip mining plus pollution control. The analyses emphasize the critical importance of controlling capital costs. Thus well-completion and labor charges are less important expenses than gas cleanup costs; these latter costs enforce volume minimization throughout all process steps. As corollary, expensive and power-consuming systems including oxygen-generating units and pumps are required. Likewise, the gas that is brought up from underground must not be permitted to become diluted with excessive steam or carbon dioxide. New process techniques which may avoid the need for most gas cleanup are discussed, and underground coal conversion is shown to have major potential environmental advantages for radioactivity release as well. Ways to increase the byproduct values are considered.

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INTRODUCTION

The underground conversion of coal (UCC) to either gaseous or liquid products has been proposed for almost one century. After a period of marked activity in the Western countries in the 1940's and 50's, and following long field experience in the Soviet Union, field experimentation in North America is again underway. These field tests have shown mixed success; many of the earlier control problems are again in evidence.

From the first it was recognized that UCC offers advantages in safety over other coal technologies, and more recent environmental interest have emphasized further advantages[1,2]:

A. Coal energy can be utilized without many of the hazards associated with mining.

B. Coal energy can be utilized with minimal concurrent release of noxious and toxic coal constituents into the biosphere.

These advantages are still apparent (Fig. 1). Both are socio-environmental and have economic implications only when factored into the regulations that now influence the technology marketplace. This fact complicates the comparison of underground coal processing both with existing and with proposed, clean, surface technology. Yet a start must be made in this task even though it must be stated from the onset that favorable economics are not the only consideration dictating current energy policies.

With this background we then list the intent of this paper: We present an economic comparison of underground coal conversion with proposed surface technology. To make this comparison we necessarily use monetary data, even though we realize that in this period of rapidly developing technological and environmental change, economic predictions are imperfect. These numbers serve two purposes: a) Relating the costs of one technology to another leads to suggestions of relative economics, and b) Comparison of process data suggests technology development strategies for technical improvements.

Economic considerations are dependent both upon energy supplies and upon energy markets, i.e., they are site specific. This paper proposes UCC for the Four Corners Region of New Mexico. One must ask several questions of this area:

1. Is the coal supply adequate?
2. Is UCC economically competetive with surface mining?
3. Is the market adequate to handle byproducts such as sulfur or liquids synthesized in UCC or SNG?

The answer to question 1 is unclear. Certainly the coal reserves are vast, but availability is complicated by a variety of legal and environmental issues. The introduction of UCC technology, even at incrementally higher costs than present surface mining, could be highly attractive. Moreover, currently unmineable coal supplies might be addressed.

Question 2 can only be answered when environmental advantages of UCC are demonstrated. The UCC should largely avoid the land-restoration costs and the permanent environmental alterations of surface mining. Moreover, if radioactivity emission standards are set for fossil-fueled power plants, the advantage of trapping uranium and thorium underground as insoluble oxides (in the ash) may be highly significant.

Question 3 introduces the interrelationship of distant markets with one specified site. The

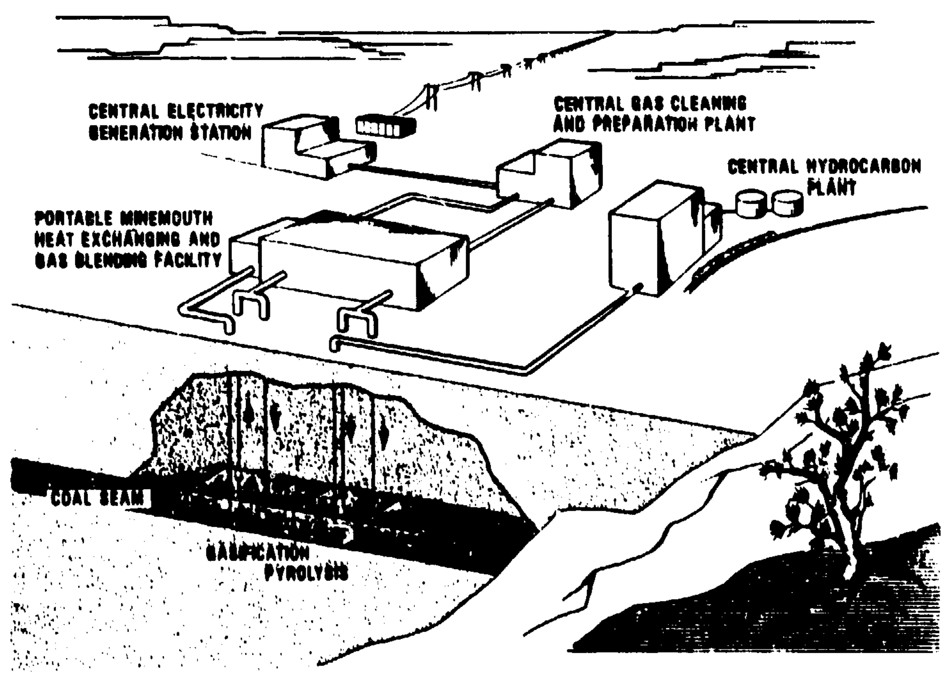

Figure 1: Underground coal conversion converts underground coal directly to clean fuels. If done in a staged fashion, UCC permits both a recovery of hydrocarbons (SNG) and of low-BTU fuel gases for electricity production.

projected short supp   thane could strongly influence the viabili   derground coal carbonization (coal pyrol   450°C in the absence of air). This direct hy   rbon production appears to have many adva. ges over the much more complicated systems now being developed for surface SNG production.

In assessing the economic viability of this concept for pyrolysis-gasification, we have derived comparative costs. We note that even with the well established Lurgi concept for surface gasification, published cost assessments vary by hundreds of percents in final cost estimates. These variations reflect different assumptions of installation costs, inflation, financing and monetary exchange rates. Therefore, the data in this paper are simply comparisons.

We turn to surface Lurgi technology since no adequate information exists for underground conversion costs. The UCC has been widely used although only in communist countries. By this selection we do not imply that Lurgi gasification should be viable for surface electric power generation. Rather, we explore if the very special advantages of UCC for clean coal technology, as mentioned above, might be limited by prohibitive economic barriers.

Case I: LURGI, Above-Ground Gasification with Air-Steam Reactants

A number of relevant and recent analyses of Lurgi and other economics have been prepared by PG&E, et al., EPRI, LETC, SRI, Gulf R&D, TRW, ORNL, Washington Public Power, and Exxon.[3-11] However, reports prepared by the Stearns-Rogers Company[12], C. F. Braun[13], and the Bureau of Mines[14,15] are more suitable for present comparative analyses. Obviously the more recent analyses would be more suitable if absolute cost projections were required.

Table 1 compiles the formal economic assumptions. Purchase prices of components and services are presented later. The coal considered for these technologies is described in Table 2. This is the same feed stock as proposed by the El Paso Natural Gas Company (EPNG) for the Burnham Coal Gasification Complex in the Four Corners Region of New Mexico.

Gasification-product yields and material-balance data assumed for Lurgi conversion and for Case II for underground conversion are listed in Table 3. Yields for the Lurgi process were taken from the EPNG study and those for the underground oxygen-steam gasification are data taken from Hanna II results (LETC).

The proposed Lurgi process chemistry is standard. Coal is delivered to the site where it is initially cleaned, powdered, and prepared for gasification. Water is brought to the site, purified, and converted to steam. Coal, steam, and compressed air are introduced into a high-temperature, high-pressure reactor where a raw fuel gas is prepared. This gas is subsequently cleaned of particulates, sulfur compounds, and byproduct C_2 and C_3 hydrocarbons. Byproduct ammonia, liquid hydrocarbons, and sulfur are removed for sale. This process is designed to produce a medium-BTU gas such as might be used for plant utilities at a surface conversion plant. More usually, oxygen-blown plants are considered for methane (SNG) synthesis.

Table 1: Assumptions Used for Economic Calculations of Lurgi Processing and as Basis for Other Assessments

SITE =	Four Corners region of New Mexico
PRODUCTION =	10^9 BTU of fuel gas/hr (to feed 1000MW$_e$ continuous, base load case)
COAL COST =	$10/ton, surface mined
PROJECT LIFE =	20 years
DEPRECIATION =	5% pa straight line on total capital requirement excluding working capital
FEDERAL INCOME TAX RATE =	48%
WORKING CAPITAL =	14 days each of coal supply and fuel output (at $2/10^6 BTU) and 0.9% of project cost
FRACTION DEBT =	0.75
DEBT INTEREST =	9%
RETURN ON BASE RATE =	10.5%
CONTINGENCY ON CAPITAL =	15%
CONSTRUCTION ALLOWANCE =	16%
OPERATING CAPITAL FOR STARTUP =	20%

Table 2: Navajo Coal Analysis

Proximate Analysis	Wt%
Dry and ash-free coal	64.50
Ash	19.25
Moisture	16.25
	100.00

Component Analysis (Dry and Ash-Free Coal	Wt%	Mol%
Carbon	76.26	48.88
Hydrogen	5.58	42.58
Nitrogen	1.32	0.72
Sulfur	1.07	0.25
Oxygen	15.74	7.57
Trace compounds	0.03	----
	100.00	100.00

Heating Value

In material balances, the higher heating value (as received) is 8664 BTU/lb.

Ash Softening Data

Softening point	2282°F
Melting point	2597°F
Flow point	2723°F

Table 3: Net Product Yields

Gasification Input[a]	Lurgi Steam-Air Gasification	*In Situ* Steam-Oxygen Gasification
Dry and ash-free coal	64.50	64.50
Ash	19.25	19.25
Moisture	16.25	16.25
Oxygen	29.61	54.59
Nitrogen	97.86	2.52
Steam	62.87	32.75
Total Input	290.34	189.86
Gasification Yield		
Dry gas	218.59	142.75
Water	43.23	26.73
Coal	1.01	---
Ash	19.25	19.25
Naphtha	1.03	---
Tars	5.84	---
Phenols	0.48	---
Ammonia	0.91	1.04
Total Output	290.34	189.77
Dry Gas Analysis (mol%)		
CH_4	5.08	9.62
C_2H_6	0.38	----
C_2H_4	0.25	----
H_2	23.26	29.50
CO	17.45	29.50
CO_2	14.83	29.50
H_2	0.23	0.37
N_2	38.52	1.51
Total	100.00	100.00

[a]Relative numbers--coal + ash + moisture = 100 parts by weight

Cost Estimates for Air-Steam, Lurgi Gasification - Capital and operating requirements for air-steam, Lurgi gasification are listed in Table 4. These relative values are presented along with the costs for underground gasification, listed as UCC (for underground coal conversion). These UCC values will be discussed latter.

Summarizing, a surface Lurgi gasification complex designed to power a 1000-MW_e electric power generator (steam boiler, for instance) in the Four Corners Region of New Mexico would cost approximately $625 x 10^6 for initial startup and an additional $60 x 10^6 annually for operation.

Although we know of no plans for surface Lurgi for electric power generation in the Four Corners, the fact is that these construction costs are not vastly different from the cost required for stack gas cleanup following conventional surface combustion. For example, $120 x 10^6 was required for modern stack gas cleaning for 300 MW generating capacity. This corresponds to approximately $400 million for the gas cleanup of a 1000-MW_e, generating facility.

Table 4: Capital and Operating Costs for Lurgi and for Underground Coal Conversion (UCC) by Current Technology

CONSTRUCTION CAPITAL	Lurgi	Current UCC	Analogous Pyrolysis UCC
Process Units			
Fuel gas production and cooling	$189	$ 14	$ 14
Fuel gas treatment and sulfur recovery	48	89	89
By product recovery	26	18	32
	$263 x 10^6	$121 x 10^6	$135 x 10^6
Well Field Systems			
Production/injection wells		$ 9	$ 9
Pyrolysis gas injection		--	2
Field piping		3	3
		$ 12 x 10^6	$ 14 x 10^6
Utilities			
Air compression	$ 55	$ 70	$ 70
Steam and power generation	55	80	80
Raw water delivery	36	28	28
Raw water treatment, cooling water, etc.	19	15	15
Oxygen plant	---	103	103
	$165 x 10^6	$296 x 10^6	$296 x 10^6
Support Facilities			
Buildings, electrical distribution, ponds, piping, storage, etc.	$ 45 x 10^6	$ 60 x 10^6	$ 60 x 10^6
Coal Handling			
Crush, screen, blend, wash, etc.	$ 33 x 10^6	---	---
Total construction capital includes contingency (Lurgi 15%, UCC 20%)	$506 x 10^6	$489 x 10^6	$508 x 10^6
OPERATING CAPITAL			
Construction allowance	$ 81	$ 78	$ 78
Startup costs	25	11	12
Working capital	14	10	10
	$120 x 10^6	$ 99 x 10^6	$100 x 10^6
Total capital required	$626 x 10^6	$588 x 10^6	$608 x 10^6

ANNUAL OPERATING COSTS

Raw materials (coal plus royalty)	$ 81	$ 15	$ 15
Labor, administration, supplies	30	41	52
Taxes and insurance	14	14	14
	$125 x 10^6	$ 70 x 10^6	$ 81 x 10^6
Byproduct revenues	$ 62	$ 10	$ 50
Net operating cost	$ 63 x 10^6	$ 60 x 10^6	$ 31 x 10^6

UNDERGROUND COAL CONVERSION USING OXYGEN-STEAM REACTANTS

Relative estimates for the costs of underground coal gasification are based on modification of the previously published Lurgi estimates. Financing assumptions used were identical in both cases (Table 1) except that 20% of the construction capital outlay was included as contingency cost for the unproven underground gasification where 15% had been included for the previously demonstrated Lurgi. One dollar royalty per ton is paid to the coal lease owners.

We assume that the coal lies 500 ft deep and in a single 20-ft seam. Initially 520 wells of 6-in diameter pipe are emplaced into the seam; the number of wells is expanded at a rate of 1030 wells per year.

Steam-Oxygen Underground Process Chemistry - With current experimental practice, as outlined in the following cost estimates, careful geological considerations define a proper site. The site selected either contains the correct amount of water for optimizing the coal gasification reactions (early Hanna experiments), or the water content is controlled by pumping to achieve the proper moisture levels (planned Hoe Creek studies). Processing regimes are operated close to seam hydrostatic pressure to reduce the influx of water and the leakage.

After selection of the site and initial surface preparation, well patterns for underground processing are drilled and completed. Wells are linked by reverse combustion, i.e., air is pumped through the seam to the combustion region. The combustion zone flux follows the air supply, thereby creating a carbonized, porous zone from the ignition well to the injection well. After linkage, the gas flow is increased, and the chemical combustion zone reverses, sweeping significant regions of the seam by forward combustion. Such forward combustion supposedly will usually consume a broad front. Hot gases (CO_2 and H_2O) generated in the oxygen-rich zones react with coal char to create fuel gases, which consist largely of carbon monoxide and hydrogen although other valuable or troublesome gases and liquids also are present.

Our analyses of the product gases emanating from both the Hanna and the Hoe Creek experiments suggest that considerable deterioration of the gas quality can occur through reactions of fuel gases with water vapor after the product gases have cooled. These side reactions are certainly controllable. In consequence of this, it will be possible to predict future improvements in oxygen-steam gasification that may favorably influence the yield data and subsequent cost extimates presented here.

Cost Estimates for Oxygen-Steam Underground Gasification - The cost estimates for present-performance, oxygen-steam, underground gasification (UCC) are indicated in Table 4, along with the Lurgi costs, which were discussed previously.

Summarizing, an oxygen-steam-blown UCC complex for powering a 1000-MW_e power generator would cost approximately \$590 x 10^6 for start up and an additional \$60 x 10^6 for operation.

THE ECONOMIC VIABILITY OF CURRENT UNDERGROUND GASIFICATION

Data in Table 4 suggest that both types of gasification, surface or underground, have roughly comparable capital and operating costs. Lurgi, of course, has been demonstrated previously and appears to be the system of choice for surface gasification complexes outside the US. Due to the ever increasing costs for stack gas cleanup, there are advantages for electric power generation if the gas cleanup is at the front end rather than in the stack. Such systems are currently under development.

Two observations are apparent:

a) Even considering the present uncertainties in underground gasification, the steam-oxygen underground system might compete favorably with surface mining, combustion and stack cleanup.

b) Surface processing costs are strongly dependent upon coal costs. Underground gasification appears to offer a competitive economic position when deeper coals are considered.

SENSITIVITY OF GASIFICATION SYSTEMS TO CAPITAL COSTS

Commercial conversion of coal to clean fuel gases requires considerable capital outlay. From the analyses given earlier, only small differences appear in capital costs when experimentally tested, underground or surface systems are considered. Improvements in the economics of either system depend largely on reducing capital costs. Note that the original capital expenses are roughly ten times the annual operating costs, and that the great majority of these expenses involve gas handling and cleaning. Product costs must be used to amortize the plant with a 20-year payout. Although financing figures vary from case to case, usually if utility financing is obtained the rate of return must be 9% per year, and with public financing it is 16%. A 15% annual return on plant equity is also required, and finally a 10.5% base gas rate return must be assured.

In total, these financing costs on the gasification process units far exceed anticipated operating costs. In fact, these analyses suggest that capital costs dominate the economics so much that operating costs, such as drilling and resource utilization, are only of secondary importance.

Table 4 shows that the largest outlays of capital for the overall system are the oxygen plant, the gas cleanup units, the gas compressors and the power generators. (Actually the oxygen plant cost is interrelated to minimizing the costs of gas cleanup and compression.) In these two UCC cases, the sizes and costs of these expensive units are influenced by the fact that a UCC product of degraded quality was assumed, the gas composition having been spoiled by contact with excess moisture which was present downstream. Without such degradation, significantly smaller, and less expensive gas-handling processes would be required. Analysis shows that improvement here would permit capital costs to be decreased by about 20%, from $590 million to $500 million. Further analysis of this problem will be presented later.

UCC WITH PYROLYSIS AND OXYGEN-CARBON DIOXIDE GASIFICATION

In the LASL modification of underground coal conversion, Fig. 2, the coal treatment involves three separate, staged, underground processes of drying, pyrolysis (carbonization) and gasification.[16,17] This coal treatment has three main objectives:

a) Generate processing regions of high porosity by drying.

b) Establish underground conditions for controlled, subsequent gasification yielding a high-quality product.

c) Recover valuable hydrocarbons during pyrolysis (carbonization).

In the following sections we analyze a series of different ways to employ pyrolysis-gasification in order to maximize the system economic return.

UCC MODIFICATIONS TO IMPROVE PROCESS ECONOMICS

Table 5 shows how gas costs could be modified by process improvements. The individual cases will be elaborated in the following discussion.

Case I: Case I is the base, surface-Lurgi case with air-steam reactants which was discussed earlier. It is again considered in Table 5.

Case II: This case represents the existing state-of-the-art for UCC as demonstrated at both Hanna (LETC) and Hoe Creek (LLL), which are the two Western, DOE field experiments. However, oxygen-steam has been substituted for air-steam during the combustion process. Minimal seam conditioning is assumed. As already indicated these underground processes are less than ideal. According to our thermodynamic analyses, approximately 40% of the heat generated underground is lost to the evaporation of water, thereby requiring excessive amounts of oxygen. Furthermore, the initially more satisfactory product formed at perhaps 900°C is degraded by reaction with down-stream water at temperatures in the vicinity of 400°C. This product-degradation reaction substitutes hydrogen fuel for carbon monoxide fuel, and burning hydrogen yields about 15% less useful heat (low heating value) than does burning a similar amount of carbon monoxide. This reaction also increases the volume of gas which must be cleaned (more steam and CO_2 are produced), and it also strains the capacity of the gas-cleaning equipment (CO_2 reacts with gas-cleaning chemicals).

But even with this built-in inefficiency (which could be reduced by moisture removal), the economic case for underground coal gasification can be made using this technology. Here the gas can be profitably sold at approximately $2.20 (utility financing or $2.75 (private financing).

Case III: This third case involves extraction of sensible heat from the gasification unit to pyrolyze another section of coal. Clearly the gas-gas heat exchange process is capital intensive and even though energy is conserved by extraction of sensible heat, the overall concept involves costs which are probably excessive.

This case offers the possiblity of good process control and energy efficiency, but product costs, mainly influenced by high capital costs for heat exchange gas compression, appear unfavorably high.

Case IV: In this case the seam is dried and pyrolyzed with hot gas which is generated in the seam and these treatments are followed by gasification with oxygen-carbon dioxide. We assume a degradation of the product gases as apparently occurs with conventional UCC oxygen-steam technology. The case is hypothetical since the assumed drying and pyrolysis would in reality preclude such product degradation (water removal). However, this case is included because it offers a direct comparison of oxygen-steam with oxygen-carbon dioxide. Costs are comparable (Cases II *vs*. IV).

Case V: This case illustrates the advantage of drying coal prior to gasification with oxygen steam. Coal drying increases porosity and residence times for gasification reactions (it decreases linear flow velocity), and it reduces subsequent product degradation because water has been removed before gasification. The drying treatment will reduce the oxygen flux, utility costs and gas-cleanup costs by about 30%. As corollary, the fuel costs drop by approximately $\$0.50/10^6$ BTU.

Case VI and VIA: In this case, heat for drying is generated *in situ* by combustion processes. Either product CO or coal could be burned with the hot product gases being used for drying of the seam well ahead of the combustion zone. Gas fluxes would be controlled to maintain drying and pyrolysis temperatures. Depending on market economics this pyrolysis could be done in a separate step or jointly with the drying process. As has already been stressed, porosity created during drying is important for subsequent underground gasification. Following this initial process, the hot section of the seam is gasified with oxygen to produce an intermediate-BTU fuel gas. Depending upon economics, either carbon dioxide or steam from the earlier drying step is introduced with the oxygen to moderate the exothermic gasification reactions in this porous bed. Specifically this process possibility offers two distinct advantages:

a) Creation of a highly porous, dry, reaction zone for controlled and optimized gasification processes,

b) Separate hydrocarbon removal (a hydrogen-enriched cut is removed).

The economics of Case VIA apply if the pyrolysis gas can be economically upgraded, perhaps by refrigerative adsorption, to produce an enhanced-BTU product stream with a heating value near 1 300 BTU/scf compared to the more usual value, for methane, of 1 000 BTU/scf. This product would be blended with other natural gas supplies for pipeline transmission to distant markets. The shipping cost per blended therm of this product stream would be only about 3/4 the usual cost.

Byproducts of the product gas recovery would include a) carbon monoxide and hydrogen which would be sent to the clean, intermediate-BTU gas stream, b) heavier molecular weight hydrocarbons, c) hydrogen sulfide which ultimately would be converted to sulfur and d) carbon dioxide. Carbon dioxide could be used for gasification modification, or it might be sold for use away from the plant site.

This case suggests a product with relative product cost of \$1.70 (utility financing) or \$2.15 (private financing) per million BTU while, if a high heating value gas can be recovered, the extra revenue would lower these costs by approximately \$0.10 per 10^6 BTU (Case VIA).

Case VII and VIIA: The last modifications consider the distinct possibility that underground pyrolysis will effectively clean sulfur from coal char. Should this happen, then the majority of sulfur contained in these subbituminous coals will be removed prior to the gasification step. This possibility has been demonstrated. Pyrolysis typically will remove a large fraction of organic sulfur along with elemental and some pyritic sulfur. Also, hydrodesulfurization processes are very similar to processes which will occur during pyrolysis of large blocks of coal and hydrodesulfurization is being tested for potential commercial coal cleanup above ground. Such sulfur could be recovered during normal gas cleaning operations involved with synthesis-gas production. Underground limestone will remove both sulfur and hydrogen sulfide, creating calcium sulfide initially, then calcium sulfate as the processing environment becomes oxidizing.

Oxygen utilization during underground gasification is dictated because of the necessity to reduce gas-cleanup costs through minimizing gas volumes. If adequate sulfur removal occurs through the combination of a separate step prior to char gasification, and sulfur entrapment as harmless calcium sulfate, then such costly gas cleaning may not be necessary. In this case, air gasification will produce an adequate fuel for electric power generation. Oxygen probably would still be required to supply pyrolysis thermal energy, however, so that the product quality from that stream is maximized.

Case VII, without separate recovery of the high-heating-value gas, suggest economics at approximately \$1.40/10^6 BTU (utility financing) or about \$1.85/10^6 BTU (private financing). Recovery of the super-BTU gas lowers these prices accordingly (Case VIIA) so that utility financing could produce product gas at a cost of \$1.35/10^6 BTU. As a comparison, large utilities currently buy compliance, low-sulfur coal for approximately \$2.00/10^6 BTU; as corollary, these costs for UCC are considerably lower than the existing fuel costs for surface combustion facilities.

TRACE ELEMENT MASS BEHAVIOR INCLUDING URANIUM

Although this analysis is directed at systems consistent with present conditions, it is worthwhile to include brief discussions of trace element release. Uranium is particularly troublesome.

There is increasing concern about the release of radioactive emissions from coal-fired generating stations. Underground coal conversion becomes particularly attractive because much of the total of radioactive constituents could be effectively contained underground in the char ash.

The gas phase transport of uranium occurs by two types of mechanism: a) Halides and oxides, particularly those of higher valence states, are volatile and exhibit gaseous behavior at elevated temperatures. b) During combustion, solid uranium constituents can be physically swept along with the ash particles. The conditions of burning finely powdered coal are particularly favorable for uranium transport because of the oxidizing nature of the reactive environments (higher valence states), high temperatures and high flue velocities.

Quite the opposite is the case for underground conversion. First, excess oxygen needed for combustion is totally consumed in the process zone so that reducing conditions dominate in the exit side of the gas stream. Second, any uranium species must contact unreacted coal or coal char. If pyrolysis has been carried out prior to gasification, then the char will reduce and effectly trap any gaseous uranium. Third, because the coal is not finely divided, the linear gas velocities are not excessive and therefore particulate transport will be minimized.

Likewise in the longer term, aqueous migration of uranium species following underground processing should be of lesser importance. Uranium almost certainly is redeposited in the coal following aqueous transport. Oxidized uranium species dissolved in underground water are reduced. The reduced uranium is insoluble and is effectively trapped. Much the same mechanism should occur following underground conversion. Incoming water will rapidly contact residual coal or coal char and dissolved uranium should again be efficiently trapped in the subsurface environment.

It is unlikely that most trace elements other than those which form highly volatile species, such as H_2S, will leave the processing zone. The relatively low linear gas velocities during char gasification, the existence of both oxidizing and reducing conditions through which all products must migrate, and the presence of silica, limestone, or both, all suggest that trace element release from UCC will be markedly decreased from similar release during surface combustion unless stack cleanup procedures are followed.

SUMMARY

Underground coal conversion potentially offers utilization of the southwestern United States' vast coal reserves in an environmentally acceptable manner with minimal disruption to the biosphere. These analyses, given in this paper, along with others, suggest that the UCC technology we discuss here (should suitable and reliable underground processing be developed) could be factored into the Southwestern US energy supply with acceptable economic return.

Process improvements center around increasing product gas quality (heat content). Energy content is related to production; gas volume is related to cleanup costs. Quite obviously it is economically advantageous to minimize the volume of product gas, which must be cleaned. The analyses presented here clearly show that even modest improvements in overall process efficiencies make significant changes in gas cleanup costs and significantly influence consumer energy costs. More importantly, such improvements markedly decrease capital requirements for power generation.

Underground processing using linked vertical wells in subbituminous coals depends upon porosity generation caused by thermal processing. Water removal occurs no matter what processing strategy is utilized. However, since water removal concurrently with underground gasification degrades product quality, it makes good sense to remove water by an initial separate processing step. The water removal will involve drainage of liquid water and initial thermal processing prior to gasification. Improvements of process economics which are associated with water removal are clearly shown in Table 5.

Pyrolysis-gas removal has less influence on the overall costs for electric power generation. However this byproduct stream does make a significant cost contribution and can increase methane supplies. One can project increased gas prices in the near term, and consequently such a contribution will become ever more favorable. Gas supplies produced in this way would be tied to electrical generation expansion. However a potentially large supply could result from underground processing.[18]

Table 5: Effects of Process Modifications upon the Costs of Underground Coal Conversion

	Costs in millions								
CONSTRUCTION CAPITAL	I	II	III	IV	V	VI	VIA	VII	VIIA
Well field systems	--	$ 12	$ 14	$ 14	$ 12	$ 14	--	$ 13	--
Coal handling	$ 33	--	--	--	--	--	--	--	--
Processing units	263	121	234	135	91	105	--	100	--
Oxygen plant	--	103	106	106	73	76	--	20	--
Gas compression	55	70	152	70	60	60	--	70	--
Steam and power plant	55	80	120	80	65	65	--	60	--
Miscellaneous utilities	55	43	43	43	43	43	--	40	--
Support facilities	45	60	60	60	60	60	--	50	--
	$506	$489	$729	($508)	($404)	($423)		$355	
OPERATING CAPITAL	$120	$ 99	$142	$100	$ 91	$ 94		$ 67	
ANNUAL OPERATING COSTS									
Coal plus royalty	$ 81	$ 15	$ 15	$ 15	$ 8	$ 10		$ 10	
Labor, overhead, etc.	44	55	60	66	55	60		60	
Byproduct revenues	-62	-10	-50	-50	-10	-40	($-70)	-40	($-70)
	$ 63	$ 60	$ 25	$ 31	$ 53	$ 30	$ 0	$ 30	$ 0

GAS COSTS PER MILLION BTU	Costs in dollars I	II	III	IV	V	VI	VIA	VII	VIIA
Utility financing	$2.30	$2.20	$2.85	($2.15)	($1.70)	($1.70)	($1.60)	$1.40	($1.35)
Private financing	$2.85	$2.75	$3.65	($2.70)	($2.10)	($2.15)	($2.05)	$1.85	($1.80)

Case I - Lurgi air-steam gasification

Case II - UCC with oxygen-steam; product gas is partially degraded before emerging to surface, consistent with current practice.

Case III - Pyrolyze first, then use dry, permeable char for gasification with oxygen-carbon dioxide; as designed this case involved excessive costs for compression, heat exchange, etc.

Case IV - Pyrolyze first, then use dry, permeable char for gasification with oxygen-carbon dioxide; assume that the product gases are degraded as much as with current UCC practice as in Case II.

Case V - Dry coal thoroughly before gasification with oxygen-steam; product gas is only slightly degraded before emerging to the surface.

Case VI - Burn a small amount of fuel underground for preliminary drying and pyrolysis, then use oxygen-carbon dioxide for gasification; this case is comparable with Case V for oxygen-steam.

Case VIA - This case is like Case VI except that we assume an economically suitable cryogenic absorption system has been developed for recovery of high-BTU methane mixture.

Case VII - In this case we assume that the pyrolysis removes much of the sulfur and that sulfur separations accompany the byproduct recovery. Further, we assume that limestone trapping of remaining sulfur produces harmless $CaSO_4$ underground and that above-ground sulfur removal is not necessary. In this case the char can be burned with air, not oxygen.

Case VIIA - Here, as with Case VIA above, we assume that high-BTU methane-containing gas can be recovered for blending into natural gas supplies going to California.

( ) Parentheses indicate estimates arrived at by analogy with calculated values.

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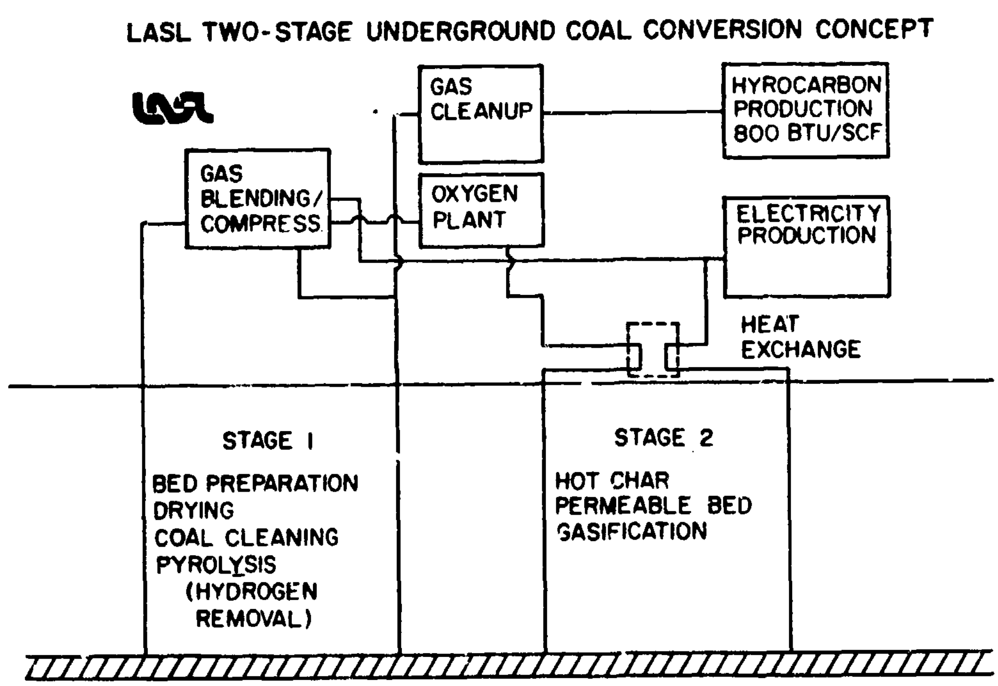

Figure 2: Underground seam is first treated with hot gases to enhance porosity simultaneously removing low molecular weight hydrocarbons. Finally underground gasification (stage 2) is completed on the hot char. Heat for Stage 1 is generated underground by chemical reactions.